UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

PJM Interconnection, L.L.C. Docket Nos. ER03-1086-001
ER03-1086-002
ER03-1086-003

ORDER ON REQUESTS FOR REHEARING AND CLARIFICATION AND ON COMPLIANCE FILING

(Issued July 9, 2004)

1. In this order, we address requests for rehearing and clarification of our September 15, 2003 Order[1] in which we conditionally accepted changes to the PJM Tariff and the Operating Agreement of PJM Interconnection, L.L.C. that were intended to expand and clarify provisions regarding lost opportunity cost compensation to generators.

I. Background

2. On July 17, 2003, PJM Interconnection, L.L.C. (PJM) filed with the Commission revisions to the PJM Open Access Transmission Tariff (PJM Tariff) and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (Operating Agreement) to expand and clarify the provisions in PJM's market rules pertaining to lost opportunity cost compensation to generators (July 17 Filing). Specifically, the July 17 Filing was intended to: (1) distinguish between the various types of generating units participating in the PJM market, which operate and are dispatched differently in ways relevant to a more accurate determination of opportunity costs; (2) distinguish between the different situations in which the need to compensate for lost opportunity cost can arise, including how the unit's actual generation compares to its day-ahead scheduled generation, and whether the unit operated on a cost-based bid or a market-based bid; and (3) reflect the effects of PJM's hourly integrated settlements when generation redispatch occurs within an hour.

[1] PJM Interconnection, L.L.C., 104 FERC ¶61,291 (2003).

3. In the revision to section 3.2.3(f), the July 17 Filing provided two methods to calculate the compensation to a steam electric generating unit or combined cycle unit operating in combined cycle mode when PJM directs the unit to reduce its output due to a transmission constraint or other reliability issue.[2] Sections 3.2.3(f-1) also provided an identical method under some conditions for a combined cycle unit operating in simple cycle mode or a combustion turbine unit. According to the July 17 Filing, such units will receive compensation based on one of two methods, depending on the relationship between the real time hourly integrated output of the unit (i.e., its actual output level) and the day ahead scheduled output of the unit. If the real time hourly integrated output is greater than or equal to the day ahead scheduled output of the unit, then the desired level of output for the unit[3] is compared to the unit's actual generation in determining the level of generator compensation. However, if the real time hourly integrated output of the unit is less than the day ahead scheduled output of the unit, then the day ahead scheduled output of the unit is compared to the unit's actual generation in determining the level of generator compensation.

4. Also in its July 17 Filing, PJM proposed a new section 3.2.3 (f-2) on Original Sheet No. 112A of its Operating Agreement and Original Sheet No. 380B of its Tariff under which PJM would compensate hydroelectric resources if their output is altered for reliability reasons in the same manner as provided in "sections 3.2.2A(d) and 3.2.3A(f)."

5. Consumers Energy Corporation (CEC) filed comments that stated that it is not clear that the distinction between whether the real time hourly integrated output is greater than, equal to, or less than the day ahead scheduled output justifies a different compensation method. CEC pointed out that if a unit is scheduled day ahead to provide 300 MW, and the Locational Marginal Price (LMP) justifies a real time dispatch of 350

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[2] The first formula is (LMPDMW-AG) x (URTLMP-UB) and is applicable whenever the real time output of the unit is greater than or equal to the day ahead scheduled output. The second formula is (DAG-AG) x (URTLMP- UB), and is applicable whenever the real time output of the unit is less than the day ahead scheduled output. LMPDMW, or LMP *Desired* MW, is defined as the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP. DAG is defined as the day-ahead scheduled unit output for the hour. AG is defined as the day-ahead scheduled unit output for the hour. URTLMP is defined as the real time LMP at the unit's bus. UB is defined as the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating.

[3] I.e., the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time locational marginal price (LMP).

MW, but reliability concerns cause the PJM dispatcher to reduce output to 301 MW, then the generator will receive compensation equal to 49 MW (350-301). However, if reliability concerns had caused the dispatcher to reduce output to 299 MW, then the generator's compensation would have equaled 1 MW (300-299).[4] CEC proposed an alternate method that would compensate the generator using the greater of the two methods. CEC also asserted that section 3.2.3(f-2) makes an incorrect reference to section 3.2.3A(f). According to CEC, the correct reference should have been section 3.2.3(f).

6. In its September 15, 2003 Order (September 15 Order), the Commission directed PJM to revise section 3.2.3 (f-2) by removing the reference to section 3.2.3A(f) and replacing it with the proper reference to section 3.2.3(f), the section for compensating steam-electric generating and combined cycle units that PJM revised in the filing.[5]

7. The Commission dismissed CEC's argument concerning PJM's proposed method for generator compensation for steam electric generating units or combined cycle units operating in combined cycle mode, as an incorrect analysis of its own example. We stated that PJM's proposed method compares the day-ahead scheduled output with the real-time hourly integrated output of the unit, which we interpreted to mean the desired level of output that the generator would have produced had it not been curtailed, rather than the unit's actual output. Based on this interpretation, we held that since actual output does not determine which formula is used, the same formula would be used in both of CEC's posed hypothetical scenarios.

II. Compliance Filing and Rehearing Request

8. PJM made a compliance filing on September 30, 2003 (September 30 Filing) in Docket No. ER03-1086-001 revising section 3.2.3 (f-2) as required by the September 15, 2003 Order. However, PJM stated that the original reference was correct. It stated section 3.2.3A(f) on First Revised Sheet No. 115 of its Operating Agreement and Second Revised Sheet No. 384A of its Tariff provides the method to be used for hydroelectric resources and that this method, which is the unit's change in output times the absolute value of the difference between the expected LMP at the generation bus and the offer price, is different from the method in section 3.2.3(f) for steam and combined cycle units. PJM asked the Commission to reconsider the September 15 Order and reject the compliance filing.

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[4] See Appendix for graphs illustrating CEC's example.

[5] Section 3.2.3 (f) is on First Revised Sheet No. 111, Original Sheet No. 111A, and First Revised Sheet No. 112 of PJM's Operating Agreement, Third Revised Rate Schedule FERC No. 24. It is on First Revised Third Revised Sheet No. 380 and Original Sheet No. 380A of PJM's FERC Electric Tariff, Sixth Revised Volume No. 1.

9. On October 9, 2003, PJM made a request for rehearing in Docket No. ER03-1086-002. It reiterates the statements it made in the compliance filing and also states that the compensation method in section 3.2.3(f) is not intended to apply to hydroelectric resources because they do not supply energy offers which can be used to determine opportunity costs, but that replacement value must be used instead in the compensation calculation for these resources. PJM asks the Commission to grant rehearing, reinstate the original reference to section 3.2.3A(f), and reject the compliance filing as moot.

III. Notice of Filings and Responsive Pleadings

10. Notice of PJM's September 30 Filing was published in the Federal Register (68 Fed. Reg. 65,263 (2003)). A timely motion to intervene and protest was filed by CEC, requesting that PJM's filing be revised or rejected. CEC also filed a Request for Clarification of the Commission's September 15 Order. On November 7, 2003, PJM filed an answer to CEC's Request for Clarification.

11. CEC's Request for Clarification argued that the Commission should reconsider its rejection of CEC's alternative proposal because the Commission misinterpreted the definition of "real-time hourly integrated output" in accepting PJM's proposed revisions. CEC claimed that the Commission based its decision in the September 30 Order on a definition of "real-time hourly integrated output" as "the point on the cost curve where the generator would have produced had it not been curtailed." CEC noted that such a definition for "real-time hourly integrated output" does not appear in the PJM Tariff. CEC therefore asserted that the Commission's misinterpretation of "real-time hourly integrated output" eliminates any validity from the Commission's rejection of its proposal to compensate generators using the greater of the two methods. CEC also noted that PJM agreed with CEC that the Commission, not CEC, misinterpreted CEC's example.

12. In its answer to CEC's request for clarification, PJM asked the Commission to reject CEC's request, arguing that CEC's alternate proposal would overcompensate generators. PJM noted that the Commission did indeed misinterpret the meaning of the term "real-time hourly integrated output" and, as a result, CEC's hypothetical example. However, PJM asserted that its Tariff revisions compensate units appropriately based on the settlement they would have received had the LMP solved consistently with the dispatch, a cornerstone of the PJM market. By contrast, PJM argued that calculating opportunity cost based on the megawatts the unit would have generated at the actual real-time price does not approximate the settlement that would have occurred had the real-time price solved correctly, and in essence overcompensates the market seller based on a hypothetical output level that was not, in fact, desired.

IV. Data Request

13. On April 8, 2004, Commission Staff issued a data request, directing PJM to provide further specific information about its Tariff revisions. On April 23, 2004, PJM responded to Staff's data request. PJM stated that the opportunity cost calculations were intended to strike a balance between providing the necessary compensation to provide incentive for generators to follow PJM dispatch instructions without resulting in overcompensation and excessive charges to load. PJM reiterated that the lost opportunity cost calculation is intended to reproduce the settlement that would have occurred if the LMP had solved consistently with the dispatch, which occurs the vast majority of the time. PJM did note however, that in the extremely unlikely example cited by CEC, there would be a counterintuitive result and a discontinuity occurs. PJM claims that this in no way invalidates the accuracy and intention of the calculation, that the overall approach and intent of the lost opportunity cost calculation is reasonable, and that it is preferable to the approach suggested by CEC which could result in compensating generators at levels higher than needed to provide an incentive for the desired conduct.

V. Discussion

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. ' 385.214 (2002), the timely, unopposed motion to intervene filed by CEC serves to make them parties to this proceeding. We will accept PJM's answer to CEC's protest.

15. PJM filed the tariff provisions at issue here in order to better reimburse generators for lost opportunity costs when generators are instructed to reduce output, and to provide an incentive for the generators to comply with PJM's dispatch instructions. While the first formula (which calculates opportunity cost compensation based on the difference between desired and actual output) provides the proper reimbursement for lost opportunity costs, the second formula (for dispatch at outputs below day ahead schedules) does not. Therefore, the Commission will require PJM to revise its tariff provisions to apply the first formula to all dispatch instructions to reduce output under section 3.2.3(f) and (f-1) regardless of whether they are above or below the day ahead scheduled volumes.

16. PJM's Answer makes clear that the assumption underlying the Commission's September 15 Order, that the "real-time hourly integrated output" equates to the unit's offer curve was incorrect.[6] In fact, PJM did not define the meaning of real-time hourly

[6] PJM Answer at p. 3. PJM states that this phrase refers to the actual output, rather than the output on the unit's offer curve.

integrated output. Therefore, the Commission needs to reconsider CEC's protest to that filing, and the Commission finds that this protest has merit.

17. PJM's proposal contains two formulas for compensation. The first compensates a generator when its actual output is above its scheduled day-ahead output. In this situation, a generator would be compensated for the reduction in output below its desired output level. The second compensates a generator when its actual output is below the scheduled day-ahead output. In this case, a generator would be paid for the reduction in output below its day-ahead scheduled output. Consumers Energy, in its protest to the July 17 Filing and in its request for clarification, raises a concern that the second formula may under-compensate generators that would have found it profitable to increase output in real-time above the scheduled day-ahead quantity.

18. The Commission finds that the second formula will result in inadequate compensation when the real-time LMP would otherwise properly result in generators producing higher than their scheduled day-ahead output in response to market signals. The second formula will compensate the generator only for the difference between the reduced output level directed by PJM and the day ahead scheduled output, not at the higher desired output level at the real-time LMP. PJM attempts to justify the lower compensation under the second formula by stating that solving LMP consistent with the PJM's actual dispatch instructions[7] is "a cornerstone of PJM's market." But this justification does not explain the disparity in application of this principle when a generator is directed by PJM to produce at either above or below its day-ahead scheduled output. The only basis offered by PJM is its belief that generators that are directed to produce below their day-ahead scheduled level do not need to be compensated at levels higher to provide an incentive for them to honor the dispatch instructions, but PJM has provided no support whatsoever for this assertion.

19. A formula purporting to provide opportunity cost compensation should be designed such that the formula as nearly as possible results in full opportunity cost (i.e., lost profits) compensation. When the real-time LMP is higher than the day-ahead price, an incentive exists for a generator to produce more than the day-ahead scheduled amount because the generator will realize greater profits if it produces at the higher level. But if PJM instructs the generator to produce less than its desired output and less than its day-ahead schedule, under PJM's proposed second formula, the generator will earn less profit and have an incentive to ignore PJM's instruction. This creates a disincentive for the generator to follow PJM's directives and may have adverse reliability implications.

[7] In its response to Commission staff data request No. 1 (c) PJM explains that solving consistently with dispatch essentially means that under normal circumstances the LMP would solve [correspond] at the point on the offer curve where the unit was dispatched by PJM.

20. This disincentive is illustrated in the Appendix to this order, which elaborates on the examples provided in the comments of Consumers Energy. In Example 2 in the Appendix, where the dispatched output is less than the day ahead scheduled output, the seller would earn $750 more profit by ignoring PJM's direction than by following it. Thus, PJM's formula does not provide the appropriate reimbursement for the lost opportunities occasioned by PJM's dispatch instruction.

21. Indeed, PJM concedes that when its below-day-ahead-dispatch formula is applied to CEC's example, the result is counterintuitive.[8] But PJM fails to provide sufficient justification for using a formula that produces counter-intuitive results in the simplest of examples.

22. At the same time, the second formula in some circumstance will result in more than full opportunity cost compensation. Overcompensation could occur when PJM directs a generator to reduce its production below its desired level in instances when the real-time price is below the day-ahead price but exceeds the avoided marginal cost of generation. In this instance the second formula would compensate a generator for production that the generator would voluntarily and profitably make without any special compensation. This result is illustrated in Example 3 of the Appendix.

23. PJM's second equation, which compensates generators for the reduction in output below its day-ahead scheduled amount, is therefore flawed and must be removed from the PJM Tariff and Operating Agreement. Therefore, we direct PJM to remove the second formula, and to revise its Tariff and Operating Agreement so that the first formula (which calculates opportunity cost compensation based on the difference between desired and actual output) is used to calculate opportunity cost compensation whenever the directed output is either above or below day-ahead scheduled output.

24. As discussed above, PJM has not provided a definition of the term "real-time hourly integrated output" in the PJM Tariff or the PJM Operating Agreement. Therefore, when PJM refiles, it needs to include a definition of this term in its tariff that is appropriate to the revised tariff provision.

25. The Commission grants PJM's rehearing request, agreeing with PJM that the original reference to section 3.2.3A(f) is the correct reference. Accordingly, the Commission dismisses the compliance filing.

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[8] PJM Response to Staff's Data Request at 6.

The Commission orders:

(1) The Commission grants PJM’s rehearing request in Docket No. ER03-1086-002.

(2) PJM’s September 30 Filing in Docket No. ER03-1086-001 is dismissed.

(3) PJM is directed to make a compliance filing within thirty (30) days of issuance of this order, as discussed herein.

By the Commission.

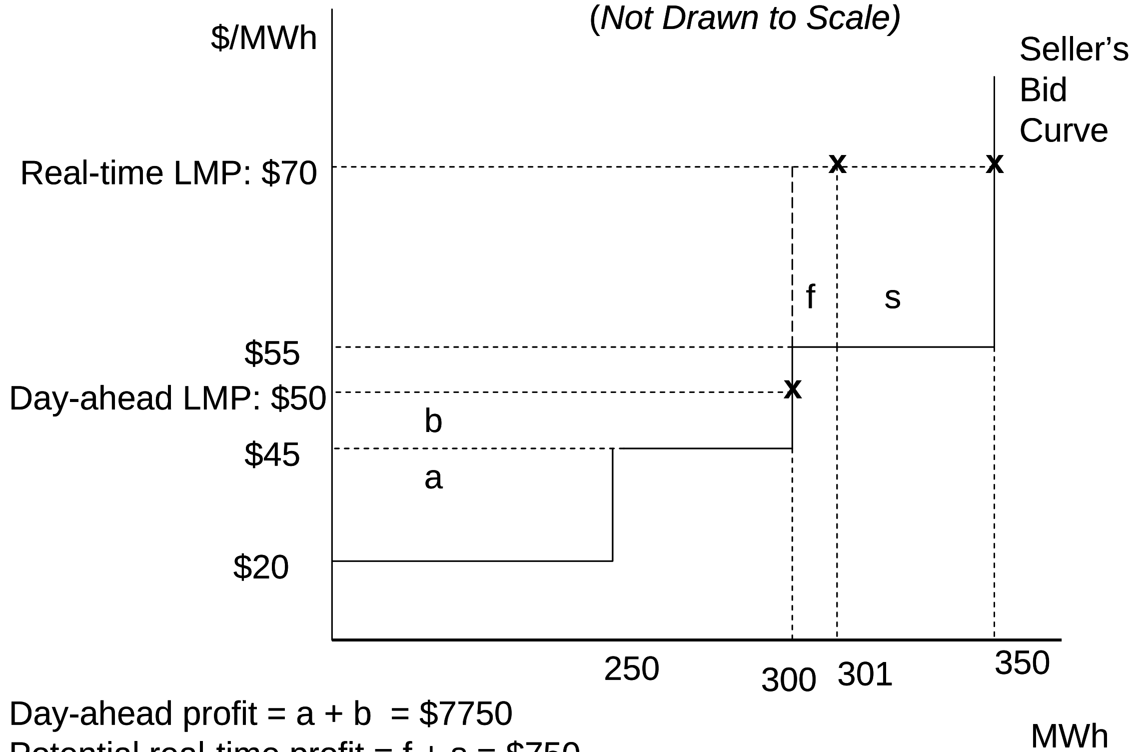
(S E A L)

Linda Mitry,
Acting Secretary.

APPENDIX

Example 1: The real-time price exceeds the day-ahead price and the directed dispatch is *above* the day-ahead schedule.

Figure 1 – Real-Time Price Exceeds Day-Ahead Price
RT Instructed Dispatch Above Day-Ahead Schedule
(*Not Drawn to Scale)*



Day-ahead profit = a + b = $7750
Potential real-time profit = f + s = $750
Foregone profit from PJM instruction = s = $735

Consider a seller that has submitted a bid curve (reflecting its marginal variable production costs at various output levels) that is illustrated in Figure 1. The seller would incur marginal costs of $20/MWh for production up to 250 MWh, $45/MWh for production between 250 and 300 MWh, and $55/MWh for additional production up to its capacity of 350 MWh.

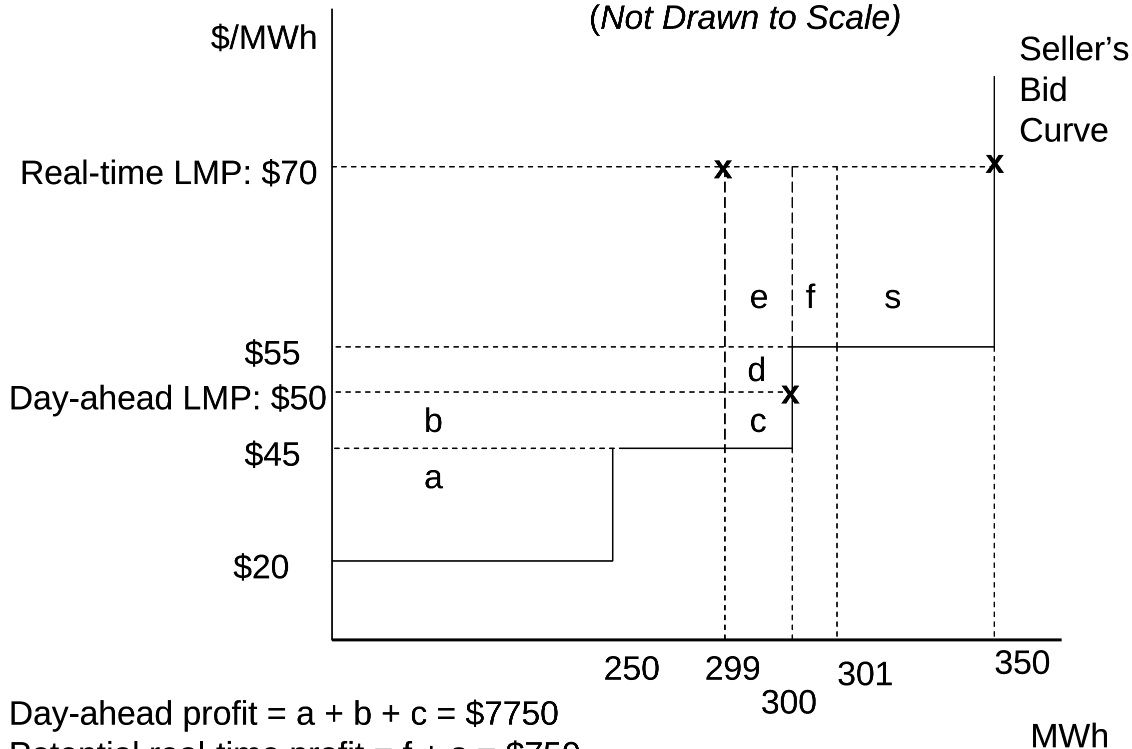
As in the Consumers example, the seller is scheduled for 300 MWh in the day-ahead market. Suppose that the day-ahead price (i.e., the LMP) is $50/MWh. The seller could make a profit of $30/MWh (i.e., the difference between the $50 price and its $20 marginal cost) for the first 250 MWh (for a total of $7500) and a profit of $5/MWh for each of the additional 50 MWh in its day-ahead schedule (for a total of $250 for the additional 50 MWh) – for a total profit of $7750. This is represented in Figure 1 by the area between the dashed line at the $50 day-ahead price and the seller's bid curve, i.e., the combined areas of a + b. Suppose that the real-time price rises to $70/MWh. At that price (as in the Consumers example), the seller's bid curve indicates that it would want to produce 350 MWh – i.e., an additional 50 MWh above its day-ahead schedule. The seller could earn an additional real-time profit of $15/MWh (i.e., the difference between the $70 real-time price and its $55/MWh marginal cost for output above 300 MWh) for each of the additional 50 MWh, for a total additional real-time profit of $750 (i.e., $15 x 50 MWh). This is represented by the area between the dashed line at the $70 real-time price and the seller's bid curve for the last 50 MWh of production, i.e., the combined areas of f + s.

Suppose that PJM directs the seller in real time to produce less than the 350 MWh that the seller wants to produce. The Consumers example considers two scenarios. In the first scenario (illustrated in Figure 1), the seller is directed to produce 301 MWh, which is 1 MWh *more* than the day-ahead schedule of 300 MWh but 49 MWh less than the seller's desired production. In the second scenario (illustrated in Figure 2), the seller is directed to produce 299 MWh, which is 1 MWh *less* than the day-ahead schedule of 300 MWh and 51 MWh less than the seller's desired production.

In the first scenario, if the seller produces 301 MWh as directed by PJM, the seller would earn a real-time profit on the additional 1 MWh of production above its day-ahead schedule of $15 (i.e., area f in Figure 1). The seller would forgo a real-time profit on the other 49 MWh that it wanted to produce (i.e., area s), for a total forgone profit of $735 (i.e., $15/MWh x 49 MWh). Under PJM's two-formula proposal, the seller would receive an opportunity cost payment of $735 in this first scenario to fully compensate it for its forgone profits. That is, when the directed level of production exceeds the seller's day-ahead schedule, PJM proposes to pay the seller its per MWh forgone profit (i.e., the difference between the real-time price and the applicable marginal cost, $15 = $70 - $55) for the reduction in its production *below its desired level*, (i.e., 49 MWh). This results in an opportunity cost payment of $735 = $5 x 49 MWh. Thus, the seller's combined real-time profit from real-time energy sales and the opportunity cost payment would be $750 (i.e., $15 + $735 = areas f + s), which is the same as the real-time profit from producing at its desired level of production. As a result, the seller would have no incentive to ignore PJM's directions in this scenario.

Example 2: The real-time price exceeds the day-ahead price and the directed dispatch is *below* the day-ahead schedule.

Figure 2 – Real-Time Price Exceeds Day-Ahead Price
RT Instructed Dispatch Below Day-Ahead Schedule
(*Not Drawn to Scale)*

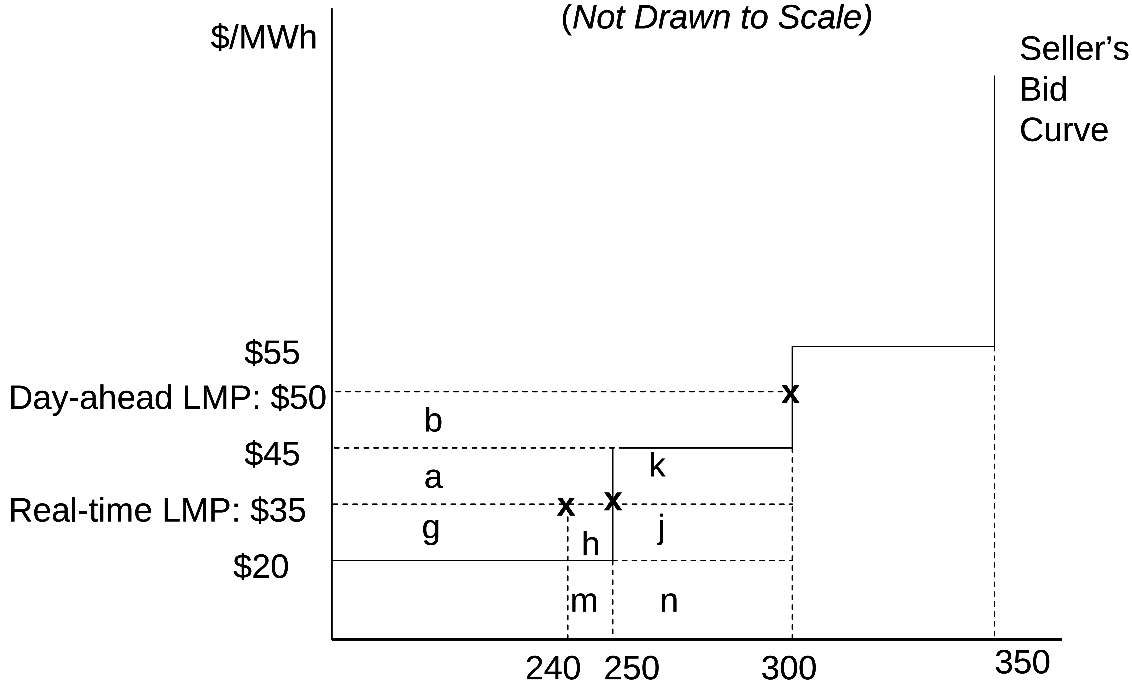


Day-ahead profit = a + b + c = $7750
Potential real-time profit = f + s = $750
Net buy-back cost = c + d + e = $25

In the second scenario (illustrated in Figure 2), if the seller produces 299 MWh as directed by PJM, the seller would be required under the market rules to buy back – at the real-time price of $70 – the 1 MWh of production below the day-ahead schedule of 300 MWh. Of course, the seller would avoid incurring the $45 marginal cost of producing the 1 MWh, so that the net cost of buying back the 1 MWh would be $25 (i.e., $70 - $45), represented by the combined areas c + d + e in Figure 2. Under PJM's two-formula proposal, the seller would be compensated for this net buy-back cost. That is, when the directed level of production is less than the seller's day-ahead schedule, PJM proposes to pay the seller the net per MWh buy-back cost (i.e., the difference between the real-time price and the applicable marginal cost, $25 = $70 - $45) for the reduction in its production *below its day-ahead schedule,* (i.e., 1 MWh). Thus, the seller's net *day-ahead* profits would be maintained; it would earn the same profit as if it had produced the 300 MWh found in its day-ahead schedule. However, the seller would earn no positive profit in real-time, despite the fact that it could have profitably produced 350 MWh – 50 MWh more than its day-ahead schedule. The seller would forgo all of the real-time profits ($750, represented by the combined area of f + s) from producing the additional 50 MWh in real-time. PJM's proposal would not compensate the seller for any of the forgone $750 profit. Thus, the seller would earn $750 less profit by following PJM's direction, and the seller would have an incentive to ignore PJM's direction. By contrast, if the opportunity cost formula used in the first scenario were also used in the second scenario the seller would receive an opportunity cost payment for the full MWh reduction below the seller's desired production level and have no incentive to ignore PJM's direction.

Example 3: The real-time price exceeds the day-ahead price.

Figure 3 – Day-Ahead Price Exceeds Real-Time Price
RT Instructed Dispatch Below Day-Ahead Schedule
(*Not Drawn to Scale)*



Day-ahead profit = a + b + g + h = $7750
Extra profit from buy back from 300 to 250 MWh = k = $500
Net cost of buy back from 250 to 240 MWh = h = $150

It is also possible that the seller's desired real-time production is less than the day-ahead schedule (unlike in the previous examples), because the real-time price is less than the day-ahead price. At the same time, PJM could direct the seller to reduce its production below the seller's desired production. This scenario is illustrated in Figure 3, but was not discussed in the comments of Consumers Energy. As explained in the following example, PJM's proposal would provide more compensation than is needed to encourage the seller to follow PJM's direction, while the formula endorsed in the main text of the order – to pay for the output reduction below the desired amount – would avoid overcompensation.

Much of Figure 3 is the same as Figures 1 and 2. The seller's bid curve is the same, the day-ahead price remains at $50/MWh, the seller's day-ahead scheduled amount remains at 300 MWh, and the seller's net day-ahead profit remains at $7750, although the areas representing the day-ahead net profit have been relabeled as a + b + g + h. However, in Figure 3 (unlike in Figures 1 and 2), the real-time price is $35/MWh, which is lower than the $50 day-ahead price. As a result, the seller's desired production would fall to 250 MWh, which is 50 MWh less than its 300 MWh day-ahead schedule. By producing 50 MWh less than its day-ahead schedule, the seller would be required to buy back the 50 MWh at the real-time price of $35/MWh, for a total of $1750, represented by the combined areas of n + j. However, the seller would avoid incurring the $45/MWh marginal costs of producing this output, for a total cost savings of $2250, represented by the combined areas of n + j + k. The cost savings would exceed the buy-back costs, and thus the seller's profits would increase, by $500 (i.e., $2750 - $2250, represented by area k) because the seller's avoided marginal cost exceeds the real-time price. So the seller would profit by reducing its production to 250 MWh.

Suppose, however, that PJM directs the seller to reduce its production by an additional 10 MWh below its desired level, down to 240 MWh. Under PJM's market rules, the seller would be required to buy back this additional 10 MWh at the $35/MWh real-time price, or $350 in total, represented by areas h + m. Of course, the seller would avoid the $20/MWh marginal cost of producing the 10 MWh, for a cost savings of $200 (area m). But this cost savings is less than the buy-back cost by $150 (area h), since the real-time price exceeds the avoided marginal costs, so the seller's profits would be reduced by $150 if it follows PJM's direction. To remove the financial disincentive to follow PJM's direction, the seller would need to be paid for this net cost, which is equal to the difference between the real-time price and the seller's marginal cost (i.e., $15), multiplied by the reduction in output below the seller's *desired production level* of 250 MWh, (i.e., 10 MWh, which is area h). This would be compensation of $150. However, under PJM's proposal, the seller would be paid more than this amount. The seller would be paid the $15/MWh difference between price and cost, multiplied by the reduction in output below the seller's *day-ahead schedule* of 300 MWh (i.e., 60, which is area h + j). This would be compensation of $900, more than the $150 needed to remove the disincentive to follow PJM's direction.